APPENDIX

Electricity Market Restructuring and Distributed Generation

The ongoing deregulation of the generation portion of electricity markets in the United States strongly affects the prospects for distributed generation and its potential to reduce electricity costs. The structure of deregulated wholesale power markets will influence the prices for distributed generation output and for related electricity services. The levels of those prices relative to retail electricity prices will determine whether distributed generators can be used in a manner that benefits their owners without raising costs for other customers. In particular, when a retail customer can also act as a supplier of electricity by operating distributed generation, differences between prices in the retail and wholesale markets may create incentives that increase costs for other customers.

Changes in How Utilities Are Structured

The structure of wholesale and retail electricity markets varies widely throughout the United States. Historically, investor-owned utilities have supplied most of the electric power. The federal government has played a key role in developing and managing hydroelectric power in several regions. Municipal and cooperative utilities also are significant suppliers, especially of distribution services in rural areas. Many aspects of this structure have changed dramatically in the past two decades, and more changes are expected in the future.

Investor-owned utilities, which typically own an entire system of generators, transmission and distribution lines, and equipment (referred to as vertical integration), are regulated by federal and state bodies. The Federal Energy Regulatory Commission (FERC) oversees the transmission system and wholesale electricity markets. State public utility commissions govern retail markets. Traditionally, state regulators have authorized the tariffs that investor-owned retail utilities can charge, setting rates that allow recovery of past investments and a reasonable return on those investments. That structure of regulated, vertically integrated monopolies that supply electricity at prices based on embedded (historical) costs has dominated electricity markets in the United States for most of the 20th century.

But over the past few decades, the vertical structure has changed in several important ways. First, utilities have integrated the interconnection and operation of their transmission networks substantially. That integration has allowed them to provide more reliable service at lower costs by taking advantage of generation from diverse sources and "gains from trade" (agreements to exchange power) with other utilities. Approximately 150 control areas have been organized in the United States under which a single operator manages an interconnected transmission grid and power plant system, using computerized controls to balance supply and demand and maintain the system's safety and reliability. Power exchanges and sales in those areas are governed by negotiated agreements and operating rules, subject to FERC's approval.

Second, starting in the late 1970s with enactment of the Public Utilities Regulatory Policies Act (PURPA), federal and state legislatures and regulatory bodies established rules for utilities to buy power at negotiated rates from independent, nonutility producers. What has gradually emerged since then is a mixed system of utility-owned generation, bilateral transactions for power at negotiated (market-based) prices, and several regional wholesale markets for electricity organized around interconnected transmission systems. The regional markets that have developed as a result of PURPA feature power exchanges in which prices fluctuate hourly, on the basis of supply and demand.

Third, in 1999, FERC called for the establishment of independent transmission organizations throughout the United States that would operate regional wholesale electricity markets. In July 2002, the commission presented its proposal on how those markets would function. The operation that FERC envisions is similar to the way in which some regional markets, including PJM (covering several mid-Atlantic states) and the New York Independent System Operator, currently operate.

Under FERC's proposed system, generators would bid to sell power in the regional markets on an hourly basis. Bids would vary widely because of differences in the operating costs of available generators. Starting with the lowest bid and moving higher, the transmission system operator would select the generators to produce sufficient electricity to meet final demand each hour.[1] All generators selected to run would be paid the value of the highest accepted bid. If congestion on a segment of the transmission system forced the operator to run a generator whose bid was above the highest accepted bid, prices of power at the delivery points served by the congested segment would be raised to reflect the difference. As a result, the price of electricity would vary each hour depending on the incremental generation costs incurred to serve the load, and it would vary by delivery point depending on transmission congestion. Price differences resulting from congestion would be managed through a market for transmission rights between the point of generation and the point of delivery.

In FERC's system, individual generators and wholesale customers could have bilateral contracts at fixed rates. If the generator failed to meet its contracted obligation, then it would buy power in the spot market to eliminate the deficit. If the customer used more than its contracted load, then the customer would buy the excess power in the spot market.

The competitive spot market for power would establish an unambiguous incremental wholesale cost of electric power. The market-clearing (highest accepted) price in the spot market would be the cost of an additional kilowatt-hour in each hour and at each delivery point, even when the majority of the power was transmitted under long-term bilateral contracts at fixed prices.[2] The (realized or avoided) cost of an additional kilowatt-hour would be the short-term spot price.

The Impact of Electricity Pricing on Distributed Generation

Most retail electricity customers in the United States face prices that are the same during predefined periods, regardless of the wholesale cost of power in a given hour. In states that continue to set electricity prices on the basis of traditional cost-of-service regulation, those prices are based on past investments. The rates may include charges that are unrelated to the current incremental cost of production—for example, charges to recover past investments in power plants that have proven uneconomic or charges for previously signed long-term contracts with prices above those for newly constructed generation. In states that have introduced competition in retail markets, suppliers are free to offer electricity at any price, with a regulated surcharge for the transportation of the power. That surcharge may include an additional component to recover the "stranded" costs of past investments made by the old regulated utility before the switch to competition.

The difference between wholesale and retail electricity prices may induce customers to install and operate distributed generators in a manner that fails to lower, and possibly raises, costs for other retail customers. For example, a customer in a state with high rates stemming from expensive past investments can avoid those rates by operating a distributed generator and shifting the burden of recovering those past investments to the remaining ratepayers. That shift can happen even when the cost of wholesale power is below that of distributed power. Such situa-

1. In the wholesale market, the customers are retail distribution utilities. They act as intermediaries, buying electricity at wholesale prices to meet the final demands of their retail customers.

2. In the geographic area managed by the PJM Independent System Operator, for example, more than 80 percent of the power is either owned by the retail utility or purchased under long-term contracts.

tions are referred to as "uneconomic bypass" because they raise the total cost of supplying electricity to ratepayers as a group.

Even when regulated retail rates are not burdened by expensive past investments, they may fail to offer customers the incentive to operate distributed generators during periods of peak demand and high wholesale prices. That is because regulated retail electricity prices generally do not track hourly variations in wholesale prices. If a customer faces a constant retail price, as most do, it has an incentive to operate its distributed generator either continuously or not at all. As a consequence, the distributed generator may run even when the wholesale cost is lower, and it may not run even when the wholesale cost is higher.

Several strategies have been proposed to price electric power from distributed generators. One widely used method for small distributed generators is called net metering. In its simplest form, net metering allows a retail customer's electricity meter to run backwards, so that transmission onto the grid offsets purchases from the grid. The customer receives a credit from its energy service provider, at the same rate it pays to buy power, for the electricity it supplies onto the grid. Many states have already ordered private utilities to offer net metering to certain small, qualifying customers. Those customers include solar and wind generators that operate intermittently. Through 2000, 33 states had mandated some form of net metering.

Although net metering provides a ready market for distributed generation output at retail prices, its simple application does not address the problems described earlier, namely, uneconomic bypass and a lack of incentives to operate during peak periods. A second approach, advocated by many analysts, is known as real-time, or dynamic, pricing. Under real-time pricing, retail rates fluctuate at short time intervals according to variations in wholesale spot-market prices. Such rates provide the price incentives for customers to operate their units during peak periods, when wholesale prices are highest. Those rates could be offered in conjunction with net metering; in that case, credits would be based on the wholesale price of electricity in each hour rather than the average price for the month.

A range of technical and regulatory issues surrounds the design of real-time retail tariffs. Those issues include recovering the costs of special metering equipment required for tariffs and reconciling real-time rates with embedded-cost recovery. Some analysts have recommended adding a fixed charge to real-time rates to cover those costs and offering the tariffs on a voluntary basis to make them more acceptable to customers. Analysts expect that the average price of electricity under real-time rates would be lower than it would be under the current flat monthly rates. Customers who elected to receive service under the lower real-time rates would assume the risks associated with the price volatility.